REVIEW MEMORANDUM
7 **DE Admin. Code 1130 (TITLE V) OPERATING PERMIT**
Significant Permit Modification

Delaware City Refining Company
4550 Wrangle Hill Road
Delaware City, Delaware 19706
Permit No.: AQM-003/00016 – Part 1 (Renewal 2)(Revision 1) Draft/Proposed
AQM-003/00016 – Part 2 (Renewal 1)(Revision 1) Draft/Proposed
AQM-003/00016 – Part 3 (Renewal 2)(Revision 1) Draft/Proposed

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BACKGROUND

The Delaware City Refinery (DCR), NAICS Code 32411, is located on a 5,000 acre tract in Delaware City and between US Route 13 and Delaware Route 9. The DCR has the potential to emit greater than 25 tons per year of nitrogen oxides (NO_X) and volatile organic compounds (VOCs), greater than 100 tons per year of carbon monoxide (CO) and sulfur dioxide (SO_2), and greater than 25 tons per year of hazardous air pollutants (HAPs) as listed in Section 112(b) of the Clean Air Act Amendments of 1990. Therefore, the DCR is subject to the requirements of 7 **DE Admin. Code 1130**.

The DCR was owned by Star Enterprises at the time the initial Title V application was submitted to the Department. On July 1, 1998, Shell Oil Products (Shell), Saudi Refining, Inc., and Texaco Inc. formed Motiva, combining the major elements of Shell's and Star's eastern and southern refining and marketing businesses. The ownership of Star Enterprise was transferred to Motiva L.L.C. on October 1998. In October 2001, Texaco Inc. divested itself of its share in the Company. Motiva sold the DCR to The Premcor Refining Group, Inc. on May 1, 2004. On September 1, 2005, Premcor, in turn, was acquired as a wholly owned subsidiary by The Valero Energy Corporation (Valero). The Delaware City Refining Company (DCRC), a subsidiary of PBF Energy acquired the DCR from Valero on May 31, 2010. DCRC was issued a 7 **DE Admin. Code 1130** TV Operation Permit on April 5, 2011 which was renewed on May 28, 2015 for an additional 5 years. Changes that occurred in the refinery during 2011 and 2012 were reviewed and incorporated in the 2015 renewal of the permit. However, several permitting actions in the interim period, i.e., the period after the most recent permit renewal was issued as a draft, have triggered new applicable requirements as described in this memorandum have necessitated this significant permit modification.[1]

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[1] This significant permit modification includes the new applicable requirements resulting from permitting actions in 2013 and 2014. It is noteworthy that 2 specific permitting actions conducted during this period and which have been included in DCRC's application for a significant permit modification dated May 15, 2015 include the Fluid Catalytic Cracking Unit (FCCU) Low NOx Operational Flexibility Project (**Permit: APC-82/0981-OPERATION (Amendment 11)(NSPS)** issued on October 7, 2014; and the Delaware City Power Plant (DCPP) Combined Cycle Units Selective Catalytic Reduction (CCUs SCR) System Project (**Permit: APC-97/0503-CONSTRUCTION (Amendment 10)(NSPS)** issued on July 2, 2014. The FCCU Low NOx Operational Flexibility Project was permitted as a federally enforceable permit pursuant to the requirements of Section 12.3 of 7 **DE Admin. Code** 1102. Therefore, the applicable requirements in **Permit: APC-82/0981-OPERATION (Amendment 11)(NSPS)** were administratively transferred to the current TV permit for the facility. The conditions in the CCUs SCR permit (**Permit: APC-97/0503-CONSTRUCTION (Amendment 10)(NSPS)**) are not being addressed in this significant permit modification because an operation permit has not been issued at this time.

DCRC's Title V fees are paid in full.

DCRC has not requested that any information be considered confidential.

CORRESPONDENCE CHRONOLOGY

Table 1 provides a chronology of correspondence.

Table 1: Chronology of Correspondence

Correspondence/Date	Subject
Significant permit modification application submittal from DCRC dated March 6, 2014 to incorporate applicable requirements from: • **Permit: APC-81/0822-O (A2)** dated 03.08.13 • **Permit: APC-81/0808-O (A1)** dated 03.08.13 • **Permit: APC-91/0553-O (A1)(LAER)** dated 04.23.13 • **Permit: APC-95/0471-C/O (A3)(LAER)(MACT)(NSPS)** dated 03.08.13 • 40 CFR 60 Subpart Ja • Removal of Package Boiler 45-B-250	Application for significant permit modification to incorporate additional 7 **DE Admin. Code** 1102 requirements in the TV permit.
Significant permit modification application submittal from DCRC dated May 15, 2015 to incorporate applicable requirements from: • **Permit: APC-82/0981-O (A11)** dated 10.07.14[2] • **Permit: APC-90/0290-O (A10)** dated 05.19.14 • **Permit: APC-90/0291-O (A3)** dated 05.19.14 • **Permit: APC-97/0503-C (A10)(NSPS)** dated 07.02.14[3]	
Significant permit modification application submittal from DCRC dated June 30, 2016 to incorporate applicable requirements from: • **Permit: APC-90/0288-O (A10)** dated 12.23.13 • **Permit: APC-90/0289-O (A10)** dated 12.23.13 • **Permit: APC-90/0290-O (A11)** dated 12.23.13 • **Permit: APC-90/0291-O (A4)** dated 12.23.13 • **Permit: APC-97/0503-C (A9)(NSPS)** dated 12.23.13	
Significant permit modification application submittal from DCRC dated July 29, 2016 to incorporate applicable requirements from: • Removal of DCPP Boiler 80-1[4]	

[2] See footnote 1.
[3] See footnote 1.
[4] DCPP Boiler 80-1 has been permanently shut down.

EMISSION POINT AND EMISSION UNIT IDENTIFICATION

In accordance with 7 **DE Admin. Code** 1130.7.3.1, an "*application for permit renewal may address only those portions of the permit that the Department determines require revision, supplementing, or deletion*." The following refinery units and operations have undergone changes that have generated new applicable requirements which are being addressed in this significant permit modification to the Title V permit:

- Olefins Plant, Storage Tanks and Truck Loading Rack
- Ether Plant Cooling Tower
- Marine Vapor Recovery System – Piers 2 and 3
- DCPP Boilers 3 & 4 Steam injection Project
- DCPP Package Boiler 45-B-250[5]
- DCPP Boilers 1 through 4 and Combined Cycle Units I & II RGGI (Regional Greenhouse Gas Initiative) Permit (State Enforceable only)

Additionally, DCRC's flare system is now subject to the recently promulgated NSPS requirements in 40 CFR 60, Subpart Ja – Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction or Modification Commenced After May 14, 2007. These new applicable requirements are also being addressed in this permitting action.

Permit Condition 1.a – *Emission Unit Information* fully details these emission units and emission points.

INSIGNIFICANT ACTIVITIES

There is no change in insignificant activities in this permit modification.

REGULATION NO. 1102 PERMITS

The following permits have been issued to the Refinery since the last permit revision in April 2011:

- **Permit: APC-81/0822-OPERATION (Amendment 2)** for the Olefins Plant, Storage Tanks and Truck Loading Rack and **Permit: APC-81/0808-OPERATION (Amendment 1)** were issued on March 8, 2013. These permits superseded **Permit: APC-82/0822-OPERATION (Amendment 1)** and **Permit: APC-81/0808-OPERATION** both dated 06.17.1981. New emission and operational limitations and testing, monitoring and record keeping requirements have been incorporated into Part 1's Condition 3 – Table 1.d. See Table 2 for detailed changes to the Title V permit.

- **Permit: APC-91/0553-OPERATION (Amendment 1)(LAER)** was issued on April 23, 2013 for the Ether Plant Cooling Tower Restart.[6] New emission and operational

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[5] This boiler has been permanently removed from service.
[6] While the Ether Plant (Emissions Unit 43) has been permanently shut down and the refinery no longer manufactures MTBE, several components continue to operate in VOC service. Therefore, the LDAR provisions for fugitive emissions addressed in Section oa (Facility wide Requirements

limitations and testing, monitoring and record keeping requirements have been incorporated into Part 1's Condition 3 – Table 1.g. See Table 3 for detailed changes.

- **Permit: <u>APC-95/0471-OPERATION (Amendment 3)(LAER)(MACT)(NSPS)</u>** was issued on May 31, 2013 for the Marine Vapor Recovery (MVR) System. It supersedes **Permit: <u>APC-95/0471-OPERATION (Amendment 2)(MACT)(RACT)</u>**. New emission and operational limitations and testing, monitoring and record keeping requirements have been incorporated into Part 2's Condition 3 – Table 1.b. See Table 4 for detailed changes.

- **Permit: <u>APC-90/0290-OPERATION (Amendment 10)</u>** and **Permit: <u>APC-90/0291-OPERATION (Amendment 3)</u>** were issued on May 19, 2014 for Boilers 3 and 4 Steam Injection Project. It supersedes **Permit: <u>APC-90/0290-OPERATION (Amendment 8)</u>** and **Permit: <u>APC-90/0291-OPERATION (Amendment 2)</u>** both dated May 26, 2009. New Emission and Operational Limitations and testing, monitoring and record keeping requirements have been incorporated into Part 3's Condition 3 – Table 1.a. See Table 5 for detailed changes.

- **Permit: <u>APC-90/0288-OPERATION (Amendment 10)</u>**, **Permit: <u>APC-90/0289-OPERATION (Amendment 10)</u>**, **Permit: <u>APC-90/0290-OPERATION (Amendment 11)</u>**, **Permit: <u>APC-90/0291-OPERATION (Amendment 4)</u>** and **Permit: <u>APC-97/0503-OPERATION (Amendment 9)(NSPS)</u>** were issued on December 23, 2013 for DCPP Boilers 1 through 4 and DCPP Combined Cycle Units I and II for DCRC's CO_2 Budget Units under the regional Greenhouse Gas Initiative (RGGI) program. These permits superseded **Permit: <u>APC-90/0288-OPERATION (Amendment 6)</u>**, **Permit: <u>APC-90/0289-OPERATION (Amendment 7)</u>**, **Permit: <u>APC-90/0290-OPERATION (Amendment 6)</u>**, **Permit: <u>APC-90/0291-OPERATION (Amendment 1)</u>** and **Permit: <u>APC-97/0503-OPERATION (Amendment 5)(LAER)(NSPS)</u>** all dated December 16, 2008. New Emission and Operational Limitations and testing, monitoring and record keeping requirements have been incorporated into Part 3's Condition 3 – Table 1.f. See Table 6 for detailed changes.[7]

- New Applicable Requirements – 40 CFR 60, Subpart Ja: Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007. See Table 7 for details of these new regulatory applicable requirements.

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for Fugitive VOC Emissions) in Part 2, Condition 3, Table 1 of the TV permit, continue in effect and are applicable requirements.

[7] DCRC's application dated June 30, 2016 for a significant permit modification to incorporate the RGGI applicable requirements includes DCPP Boiler 80-1 as affected emissions unit. However, pursuant to DCRC's subsequent additional application dated July 29, 2016, DCRC stated that DCPP Boiler 80-1 has been permanently shut down. Therefore, the former applicable requirements of DCPP Boiler 80-1 have been deleted from the permit.

Table 2

Permit: APC-81/0822-OPERATION (A2) - Olefins Plant, Storage Tanks and Truck Loading Rack And Permit: APC-81/0808-OPERATION (A1) – Heater 134-H-101 Dated 03.08.2013			
7 DE Admin. Code 1102 Permit Condition No.	**Condition Description**	**Transferred to**	
		Permit Part	**Condition No.**
2.1.1	VOC: 2.1.1.1 0.8 TPY from 134-H-101 2.1.1.2 4.6 TPY from the storage tanks, loading rack and fugitive emissions	Part 1, Condition 3 Table 1	d.5.i.A. and B.
2.1.3	PM/PM10/PM2.5: PM/PM10/PM2.5 emissions from 134-H-101 shall not exceed 0.3 lb/mmBtu (2-hour average) and 0.8 TPY.	Part 1, Condition 3 Table 1	d.1.i.
2.1.4	SO_2: SO_2 emissions from 134-H-101 shall not exceed 3.7 TPY.	Part 1, Condition 3 Table 1	d.2.i.B.
2.1.5	CO: CO emissions from 134-H-101 shall not exceed 1.2 TPY	Part 1, Condition 3 Table 1	d.1.6.i.
4.1	Compliance with Condition 2.1.1.1. 2.1.3 and 2.1.5 shall be based on monitoring the fuel gas usage and fuel quality.	Part 1, Condition 3 Table 1	d.1.i.A, d.5.ii.A. through D., and d.6.iiA.
4.3	Compliance with Conditions 2.1.4 shall be based on the fuel sulfur content and fuel gas usage.	Part 1, Condition 3 Table 1	d.2.iii.A.
5.2.2	The rolling 12 month total emissions for each pollutant shall be calculated and recorded each month.	Part 1, Condition 3 Table 1	d.1.v.A., d.2.v.B., d.3.iv.D., d.5.iii.A. and B.; and d.6.iii.

Table 3

Permit: APC-91/0553-OPERATION (A1)(LAER) Ether Plant Cooling Tower Restart Project Dated 04.23.2013			
7 DE Admin. Code 1102 Permit Condition No.	**Condition Description**	**Transferred to**	
		Permit Part	**Condition No.**
2.1.1	PM10/PM2.5 emissions shall not exceed 0.2 grains/dry standard cubic foot and 1.7 TPY	Part 1, Condition 3 Table 1	g.2.i.
2.1.2	VOC emissions shall not exceed 5.5 TPY.	Part 1, Condition 3 Table 1	g.1.i.
3.1.	The Company shall comply with the MACT Heat Exchanger Leak Detection Requirements in 40 CFR 63.654.	Part 1, Condition 3 Table 1	g.1.ii.
4.1	Compliance with Condition 2.1.1 shall be based on the proper operation of the high-efficiency mist eliminators having a vendor guaranteed emission factor of 0.0005 % drift loss per pound of cooling water circulated and on the monitoring requirements in Condition 4.3.1.	Part 1, Condition 3 Table 1	g.2.iii.
4.2	Compliance with Conditions 2.1.2 and 3.1 shall be based on the monitoring and testing requirements in Condition 4.3.2.	Part 1, Condition 3 Table 1	g.1.iii.
4.3.1	The Owner/Operator shall conduct a quarterly test of total solids using Method 2540B of Standard Methods for the Examination of Water and Wastewater.	Part 1, Condition 3 Table 1	g.2.iii.
4.3.2	The VOC concentration in the cooling water shall be obtained in accordance with the procedures in 40 CFR 63.654 (c)(1) using a method approved by the Department. To determine the cooling water VOC concentration, samples shall be taken at the entrance and exit of the cooling tower and at the point of makeup water addition. The entrance is the point at which cooling water leaves the cooling tower prior to being returned to the process equipment. The exit is the point at which the cooling water is introduced to the cooling tower after being used to cool the process fluid. A minimum of three sets of samples shall be taken at the entrance and exit and the point of make-up water entry. The average concentrations shall then be calculated for each set of samples.	Part 1, Condition 3 Table 1	g.1.iii. and g.1.iv.
4.5	Compliance with Condition No. 3.1 shall be based on information available to the Department concerning the Company's actions with respect to such events, and shall include the Department's review of all available facts and	Part 1, Condition 3 Table 1	g.1.iii.B.

	circumstances including, but not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.		
5.2.1	Results of quarterly test of total solids using Method 2540B	Part 1, Condition 3 Table 1	g.2.v.A.1.
5.2.2	Results of cooling water VOC concentration	Part 1, Condition 3 Table 1	g.1.v.A.1.
5.2.3	Cooling water average recirculation rate in gallons per minute.	Part 1, Condition 3 Table 1	g.1.v.A.2. and g.2.v.A.2.
6.1	Emissions in excess of any permit condition or emissions which create a condition of air pollution shall be reported to the Department immediately upon discovery and after activating the appropriate site emergency plan, in the following manner: 6.1.1 By calling the Department's Environmental Emergency Notification and Complaint number (800) 662-8802, if the emission poses an imminent and substantial danger to public health, safety or to the environment. 6.1.2 Other emissions in excess of any permit condition or emissions which create a condition of air pollution may be called in to the Environmental Emergency and Complaint number (800) 662-8802 or faxed to (302) 739-2466. The ability to fax in notifications may be revoked upon written notice to the Company by the Department in its sole discretion.	Part 1, Condition 3 Table 1	g.1.vi. and g.2.vi.

Table 4

Permit: APC-95/0471-CONSTRUCTION/OPERATION (A3)(LAER)(MACT)(NSPS) Marine Vapor Recovery System – Piers 2 and 3 Dated 05.31.2013			
Condition No.	**Condition Description**	**Transferred to**	
		Permit Part	**Condition No.**
2.1.1	$PM_{10}/PM_{2.5}$ emissions from crude oil loading operations shall not exceed 0.3 lb/mmBtu and 1.4 TPY.	Part 2, Condition 3, Table 1	b.2.i.
2.1.2	SO_2 emissions from crude oil loading operations shall not exceed18.1	Part 2, Condition 3, Table 1	b.7.i.

	lb/hour on a daily average basis and 21.3 TPY		
2.1.3.1	VOC emissions shall not exceed 75.5 tons in any twelve consecutive months	Part 2, Condition 3, Table 1	b.5.i.A.
2.1.3.2	Vapors displaced during barge loading operations shall be collected and routed through the marine vapor control system and shall be reduced by 99 weight percent or to 500 ppmv of VOC	Part 2, Condition 3, Table 1	b.5.i.B.
2.1.3.3	VOC emissions from the Crude Oil Tank Farm inclusive of 281-TF-200 shall not exceed 27 TPY	Part 1, Condition 3, Table 1	fc.1.i.
2.1.4	H_2S emissions during crude oil loading shall not exceed 0.2 lb/hr on a daily average basis and 0.2 TPY	Part 2, Condition 3, Table 1	b.8.i.
2.1.5	H_2SO_4 emissions during crude oil loading shall not exceed 0.6 lb/hr on a daily average basis and 0.7 TPY	Part 2, Condition 3, Table 1	b.9.i.
2.1.6	NO_x emissions shall not exceed those prescribed in Condition 3, Table 1 jb.1.i of **Permit: <u>AQM-003/00016 – Part 1 (Renewal 1)(Revision 5)</u>** dated April 5, 2011.	Part 2, Condition 3, Table 1	b.3.i.
3.2	The throughput of crude oil shall not exceed 7,000 barrels per hour on a daily average basis and 16,425,000 barrels on a rolling twelve month basis	Part 2, Condition 3, Table 1	b.5.ii.C.
3.7	Marine vessel loading operations of gasoline products or crude oil shall not be conducted unless the MVR VCUs is/are operating properly. Proper operation is defined as operating the VCUs in accordance with 40 CFR 60.18, and with the continuous presence of a flame at the pilot during the entire loading cycle	Part 2, Condition 3, Table 1	b.5.ii.H.
3.9	The H_2S concentration in the barges being loaded with crude oil shall not exceed: 3.9.1 2,778 ppmv on a 12-month rolling average basis 3.9.2 30,000 ppmv on a daily average basis	Part 2, Condition 3, Table 1	b.7.ii.
4.3	Compliance with Condition 2.1.6 (NOx) shall be based on compliance with Condition jb.1.ii in Permit: AQM-003/00016 – Part 1 (Renewal 1)(Revision 5) dated April 5, 2011.	Part 2, Condition 3, Table 1	b.3.ii.
4.7	Compliance with Condition 3.9 shall be based on compliance with the Monitoring/Testing requirements in this permit	Part 2, Condition 3, Table 1	b.7.iii.
4.8.1	The Owner/Operator shall test each crude oil shipment to be loaded into marine vessels by ASTM D5705 Hydrogen Sulfide in Vapor Space to determine hydrogen sulfide concentration in the barge vapor space during crude oil loading. The Owner /Operator shall use this data to demonstrate compliance with the Sulfur Dioxide limitations in this permit	Part 2, Condition 3, Table 1	b.7.iii.

4.8.3	The Owner/Operator shall continuously monitor the hourly loading rate of all crudes at each pier during loading operations	Part 2, Condition 3, Table 1	b.5.iv.B.
4.8.4	Except as provided in Condition 4.8.5, the Owner/Operator shall conduct the following stack tests at 5 year intervals unless more frequent testing is required by the Department: 4.8.4.1 EPA Reference Method 5B/202 for PM_{10}/$PM_{2.5}$, including H2SO4 4.8.4.2 EPA Reference Method 25 A for VOC 4.8.4.3 EPA Reference Method 15 for H_2S 4.8.4.4 EPA Reference Method 8 for H_2SO_4	Part 2, Condition 3, Table 1	b.2.iii.B., b.5.iv.D., b.8.ii.A.1., and b.9.ii.A.1.
5.2	The following information shall be recorded: 5.2.1 Records of all ASTM D5705 Hydrogen Sulfide in Vapor Space test results in accordance with Condition 4.8.1. 5.2.2 Records for the type of fuel combusted in the MVR VCUs and hourly fuel usage. 5.2.3 Records for the hourly throughput, type of product, number of piers used and duration of each loading cycle	Part 2, Condition 3, Table 1	b.7.iv., b.1.iv.A. and

Table 5

Permit: APC-90/0290-OPERATION(A10) and Permit: APC-90/0291-OPERATION(A3) Boiler 3 and Boiler 4 Steam Injection Project Dated May 19, 2014			
Condition No.	**Condition Description**	**Transferred to**	
		Permit Part	**Condition No.**
2.1.1.2	NO_x emissions shall not exceed 0.16 lb/mmBtu from each of Boilers 3 & 4 on a 24-hour rolling average.	Part 3, Condition 3, Table 1	a.5.i.C.3.
2.1.1.3	The lb/mmBtu emissions standards for Boilers 3 & 4 shall not apply during periods not to exceed 6 hours during each planned startup and shutdown.	Part 3, Condition 3, Table 1	a.5.i.C.3.
3.1	Only desulfurized refinery fuel gas (RFG) with a hydrogen sulfide content less than 0.1 grain/dscf on a 3 hour rolling average and/or natural gas may be fired in Boilers 1, 2, 3, 4.	Part 3, Condition 3, Table 1	a.2.i.A.
3.2	Except during periods of startup and shutdown, the burner steam injection systems in Boiler 3 and 4 shall be working in a manner consistent with maintaining 0.16 lb/MMBtu NOX on a 24 hour rolling average.	Part 3, Condition 3, Table 1	a.2.i.K.
3.3	At all times, including periods of startup, shutdown, and malfunction, the owner or operator shall maintain and operate the equipment and processes	Part 3, Condition 3, Table 1	a.2.i.L.

	covered by this Permit, including all structural and mechanical components of all equipment and processes and all associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions.		
4.1	Compliance with Condition 2.1.1 for Boilers 1, 2, 3, 4 and the CCUs shall be demonstrated using a Continuous Emissions Monitoring Systems (CEMS) for NO_x and O_2. The CEMS for Boilers 1, 2, 3 and the CCUs shall conform to the applicable Performance Specifications in 40 CFR, Part 60, Appendix "B" and the Quality Assurance/Quality Control (QA/QC) procedures for NO_x CEMS in accordance with 40 CFR Part 60, Appendix "F". The CEMS for Boiler 4 shall conform to the applicable Performance Specifications in 40 CFR, Part 75, Appendix "A" and the Quality Assurance/Quality Control (QA/QC) procedures for NO_x CEMS in accordance with 40 CFR Part 75, Appendix "B".	Part 3, Condition 3, Table 1	a.5.iv.B. and a.5.iv.C.
4.3	Compliance with Condition 2.1.3 shall be demonstrated by using CEMS on Boiler 2 and by a stack test based emissions factor and fuel flow rate for Boilers 1, and 3.	Part 3, Condition 3, Table 1	a.6.iv.A.
4.4	Compliance with Conditions 2.1.4, 2.1.5 and 2.1.6 shall be demonstrated by firing only natural gas or by using annual stack test based emissions factors while firing RFG and RFG fuel flow rates for the boilers.	Part 3, Condition 3, Table 1	a.3.iv.A. and a.6.iv.A.
4.11	Compliance with Condition 3.2 shall be based on the record keeping requirements.	Part 3, Condition 3, Table 1	a.2.ii.I.
4.13	Compliance with Conditions 2.3 and 3.3 shall be based on information available to the Department, which may include, but is not limited to, monitoring results, opacity and process operating data.	Part 2, Condition 3, Table 1	ob.2. and ob.4.
5.2.1	Log of all operating hours of each boiler clearly showing the hours of operation with different fuel types, i.e., hours of operation with natural gas, refinery fuel gas, and the amount of each fuel type consumed	Part 3, Condition 3, Table 1	a.2.iii.J.
5.2.2	Rolling 24-hour heating values of the fuels combusted	Part 3, Condition 3, Table 1	a.2.iv.C.<u>2.</u>
Obsolete Title V Permit Condition Removed	Condition a.3.i.B.<u>2.</u> 0.026 lb/mmBtu heat input when firing syngas in Boiler 80-3	Part 3, Condition 3, Table 1	None
Obsolete Title V Permit Condition Removed	Condition a.3.i.D.<u>2.</u> 0.0074 lb/mmBtu heat input when firing syngas in Boiler 80-3	Part 3, Condition 3, Table 1	None
Obsolete Title V Permit	Condition a.8.iii.C. Compliance for the Boiler 80-3 shall be demonstrated by applying the stack test based SO_2 to H_2SO_4 conversion factor to the CEMS	Part 3, Condition 3, Table 1	None

Condition Removed	monitored SO_2 emissions.		

Table 6

Permit: APC-90/0289-OPERATION (Amendment 10), Permit: APC-90/0290-OPERATION (Amendment 11), Permit: APC-90/0291-OPERATION (Amendment 4) and Permit: APC-97/0503-OPERATION (Amendment 9)(NSPS) Dated December 23, 2013 for DCPP Boilers 2 through 4 and DCPP Combined Cycle Units I and II for DCRC's CO_2 Budget Units under the regional Greenhouse Gas Initiative (RGGI) Program			
Condition No.	**Condition Description**	**Transferred to**	
		Permit Part	**Condition No.**
1.1	The owners and operators of each CO2 budget source and each CO2 budget unit, at the source shall hold CO2 allowances available for compliance deductions under 7 DE Admin. Code 1147, Section 6.5, as of the CO2 allowance transfer deadline, in the source's compliance account in an amount not less than the total CO2 emissions associated with gross generation output to the grid for the control period from all CO2 budget units at the source, as determined in accordance with 7 DE Admin. Code 1147, Sections 6.0 and 8.0.	Part 3, Condition 3, Table 1	f.9.i.A.
1.2	Each ton of CO2 emitted in excess of the CO2 budget emissions limitation shall constitute a separate violation of 7 DE Admin. Code 1147 and applicable state law.	Part 3, Condition 3, Table 1	f.9.i.B.
1.3	The requirements of 7 DE Admin. Code 1147, Section 1.2.3.1 shall become effective as of January 1, 2013.	Part 3, Condition 3, Table 1	f.9.i.C.
1.4	CO2 allowances shall be held in, deducted from, or transferred among CO2 Allowance Tracking System accounts in accordance with 7 DE Admin. Code 1147, Sections 5.0, 6.0, 7.0 and 10.7	Part 3, Condition 3, Table 1	f.9.i.D.
1.5	A CO2 allowance shall not be deducted, in order to comply with the requirements under 7 DE Admin. Code 1147, Section 1.5.3.1 of, for a control period that ends prior to the year for which the CO2 allowance was allocated. A CO2 offset allowance shall not be deducted, in order to comply with the requirements under 7 DE Admin. Code 1147, Section 1.5.3.1, beyond the applicable percent limitations set out in V, Section 6.5.1.3.	Part 3, Condition 3, Table 1	f.9.i.E.
1.6	A CO2 allowance under the CO2 Budget Trading Program is a limited authorization by the Department or a participating state to emit one ton of CO2 in accordance with the CO2 Budget Trading Program. No provision of the CO2 Budget Trading Program, the CO2 budget permit application, or the CO2 budget permit or any provision of law shall be construed to limit	Part 3, Condition 3, Table 1	f.9.i.F.

	the authority of the Department or a participating state to terminate or limit such authorization.		
1.7	A CO2 allowance under the CO2 Budget Trading Program does not constitute a property right.	Part 3, Condition 3, Table 1	f.9.i.G.
1.8	Excess emissions requirements: The owners and operators of a CO_2 budget source that has excess emissions in any control period shall: 1.8.1 Forfeit the CO2 allowances required for deduction under 6.5.4.1 of this regulation, provided CO2 offset allowances may not be used to cover any part of such excess emissions; and 1.8.2 Pay any fine, penalty, or assessment or comply with any other remedy imposed under 7 DE Admin. Code 1147, Section 6.5.4.2 For purposes of the above condition, a CO2 Budget Source/affected unit shall mean Boiler 1, Boiler 2, Boiler 3, Boiler 4, CCU 1 or CCU 2.	Part 3, Condition 3, Table 1	f.9.i.H.
2.1	Compliance with Condition 1.1 shall be based on the calculation methodology described in Section 3 of DCRC's application and Attachment "A" of this permit which shall be used to determine CO2 emissions from DCRC's affected units using the natural gas consumption, electrical generation, and steam production from each CCU to calculate the rolling daily average heat input for the allocation year. During periods of power balance when the CCUs are exporting power, the rolling daily heat rate shall be used to determine the amount of CO2 allowances required for each CO2 budget unit (CCU 1 and CCU 2) for each allocation year. During periods of power imbalance, when some generation from the TGs may be exported, the conservative default heat rate of 10,000 Btu/kWh shall be used to determine the amount of CO2 allowances required for power exported during that period.	Part 3, Condition 3, Table 1	f.9.iii.A.
2.2	Compliance with Conditions 1.2 through 1.8 shall be based on the monitoring and recordkeeping requirements of this permit.	Part 3, Condition 3, Table 1	f.9.iii.B.
3.1	The Company shall monitor the following parameters as described in Attachment "A" of this permit: Daily overall power flow through the 13825 Power Line and Transformers AT1 and T6A in kWh, measured and reconciled daily	Part 3, Condition 3, Table 1	f.9.iv.A.

3.2	The Company shall monitor the following parameters as described in Attachment "A" of this permit: Calculated daily average heat rate in Btu/kWh.	Part 3, Condition 3, Table 1	f.9.iii.B.
4.1	Unless otherwise provided, the owners and operators of the CO2 budget source and each CO2 budget unit at the source shall keep on site at the source each of the following documents for a period of 10 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 10 years, in writing by the Department.	Part 3, Condition 3, Table 1	f.9.v.A.
4.1.1	The account certificate of representation for the CO2 authorized account representative for the source and each CO2 budget unit at the source and all documents that demonstrate the truth of the statements in the account certificate of representation, in accordance with 2.4 of this regulation, provided that the certificate and documents shall be retained on site at the source beyond such 10-year period until such documents are superseded because of the submission of a new account certificate of representation changing the CO2 authorized account representative.	Part 3, Condition 3, Table 1	f.9.v.A.1.
4.1.2	All emissions monitoring information, in accordance with 7 DE Admin. Code 1147, Section 8.0 and 40 CFR 75.57.	Part 3, Condition 3, Table 1	f.9.v.A.1.
4.1.3	Copies of all reports, compliance certifications, and other submissions and all records made or required under the CO2 Budget Trading Program.	Part 3, Condition 3, Table 1	f.9.v.A.1.
4.1.4	Copies of all documents used to complete a CO2 budget permit application and any other submission under the CO2 Budget Trading Program or to demonstrate compliance with the requirements of the CO2 Budget Trading Program.	Part 3, Condition 3, Table 1	f.9.v.A.1.
4.2	The CO2 authorized account representative of a CO2 budget source and each CO2 budget unit at the source shall submit the reports and compliance certifications required under the CO2 Budget Trading Program, including those under 4.0 of this regulation.	Part 3, Condition 3, Table 1	f.9.v.B.
5.1	The Company shall comply with the following administrative requirements: These permits shall be made available on the premises.	Part 3, Condition 3, Table 1	f.9.ii.A.
5.3	Liability	Part 3, Condition 3, Table 1	f.9.ii.B.
5.3.1	No permit revision shall excuse any violation of the requirements of the CO2 Budget Trading Program that occurs prior to the date that the revision takes effect.	Part 3, Condition 3, Table 1	f.9.ii.B.1.
5.3.2	Any provision of the CO2 Budget Trading Program that applies to a CO2 budget source (including a provision applicable to the CO2 authorized	Part 3, Condition 3, Table 1	f.9.ii.B.2.

	account representative of a CO2 budget source) shall also apply to the owners and operators of such source and of the CO2 budget units at the source.		
5.3.3	Any provision of the CO2 Budget Trading Program that applies to a CO2 budget unit (including a provision applicable to the CO2 authorized account representative of a CO2 budget unit) shall also apply to the owners and operators of such unit.	Part 3, Condition 3, Table 1	f.9.ii.B.3.
5.4	Effect on other authorities:	Part 3, Condition 3, Table 1	f.9.ii.C.
5.4.1	No provision of the CO2 Budget Trading Program, a CO2 budget permit application, or a CO2 budget permit, shall be construed as exempting or excluding the owners and operators and, to the extent applicable, the CO2 authorized account representative of a CO2 budget source or CO2 budget unit from compliance with any other provisions of applicable State and federal law and regulations.	Part 3, Condition 3, Table 1	f.9.ii.C.1.
5.5	Failure to comply with the provisions of these permits may be grounds for suspension or revocation.	Part 3, Condition 3, Table 1	f.9.ii.D.
Obsolete Title V Permit Condition Removed	Condition f.9.i. Operational Limitation: The annual electrical output to the grid resulting from the operation of [unit] shall not exceed 10 % of the annual gross electrical generation resulting from the operation of [unit]. The effect of this operational limitation will enable the Company to qualify for the limited exemption provided in Section 1.1.2 of Regulation 1147. To the extent that the limited exemption is not applicable to Company operations for whatever reason, including the Company's voluntary decision not to qualify for the limited exemption on a going-forward basis, then this operational limitation, and any associated compliance methodology, testing, monitoring, record keeping and reporting requirements shall not apply. However, the Company must inform the Department in writing within 30 days of determining that it does not desire to qualify for the limited exemption. *[Reference APC-90/0289 (A7), APC-90/0290 (A6), APC-90/0291 (A1) and APC-97/0503 (A5)]*	Part 3, Condition 3, Table 1	None
Obsolete Title V Permit Condition Removed	Condition f.9.ii. Administrative Requirements: *[Reference APC-90/0289 (A7), APC-90/0290 (A6), APC-90/0291 (A1) and APC-97/0503 (A5)]* A. The Company and, to the extent applicable, the CO_2 authorized account representative of a unit exempt under 1.2.2.1 of Regulation 1147 shall comply with all the requirements of	Part 3, Condition 3, Table 1	None

	Regulation 1147 concerning all time periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect. B. On the earlier of the following dates, a unit exempt under 1.2.2.1 of Regulation 1147 shall lose its exemption: 1. the date on which the restriction on the percentage of annual gross generation that may be supplied to the electric grid described in 1.2.2.1 of Regulation 1147 is removed from the unit's permit or otherwise becomes no longer applicable in any year that commences on or after January 1, 2009; or 2. the first date on which the unit fails to comply, or on which the owners and operators fail to meet their burden of proving that the unit is complying, with the restriction on the percentage of annual gross generation that may be supplied to the electric grid described in 1.2.2.1 of Regulation 1147 during any year that commences on or after January 1, 2009. **C.** A unit that loses its exemption in accordance with 1.2.2.3.5 of Regulation 1147 shall be subject to the requirements of Regulation 1147. For the purpose of applying permitting requirements under 3.0 of Regulation 1147, allocating allowances under 5.0 of Regulation 1147, and applying monitoring requirements under 8.0 of Regulation 1147, the unit shall be treated as commencing operation on the date the unit loses its exemption.		
Obsolete Title V Permit Condition Removed	Condition f.9.iii. Compliance Methodology: *[Reference APC-90/0289 (A7), APC-90/0290 (A6), APC-90/0291 (A1) and APC-97/0503 (A5)]* Compliance with the operational limitation shall be based on monitoring data. Unless an alternative methodology is approved by the Department, the percent of electrical output to the grid for each affected unit shall be calculated as follows: $\% \, PEXP_{[u]} = (PEXP_{TOT} / PGEN_{TOT}) \times 100$ where: $\% \, PEXP_{[u]}$ = Percent of annual electrical output to the grid resulting from the operation of unit "u". $PEXP_{TOT}$ = Total annual power exported by the entire facility as	Part 3, Condition 3, Table 1	None

	measured by the "make/take" electrical meters $PGEN_{TOT}$ = Total power generated by the entire facility		
Obsolete Title V Permit Condition Removed	Condition f.9.iv. Monitoring/Testing: *[Reference APC-90/0289 (A7), APC-90/0290 (A6), APC-90/0291 (A1) and APC-97/0503 (A5)]* The Company shall monitor the following parameters: A. Annual power generated by each Turbo generator unit. B. Annual power generated by direct firing of each CCU. C. Annual power output to the grid for the facility.	Part 3, Condition 3, Table 1	None
Obsolete Title V Permit Condition Removed	Condition f.9.v.Recordkeeping: *[Reference APC-90/0289 (A7), APC-90/0290 (A6), APC-90/0291 (A1) and APC-97/0503 (A5)]* The company shall maintain following records for 10 years from the date the records are created: A. Annual power generated by each Turbo generator unit. B. Annual power generated by direct firing of each CCU. C. Annual power output to the grid for the facility. The 10-year period for keeping records may be extended for cause, at any time prior to the end of the period, in writing by the Department. The Company shall bear the burden of proof that each affected unit met the restriction on the percentage of annual gross generation that may be supplied to the electric grid. *[Reference APC-90/0289 (A7), APC-90/0290(A6), APC-90/0291(A1) and APC-97/0503(A5)]*	Part 3, Condition 3, Table 1	None

Table 7

New Applicable Requirements – 40 CFR 60, Subpart Ja Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007			
Condition No.	**Condition Description**	**Transferred to**	
		Permit Part	**Condition No.**
	Sulfur Dioxide: The owner/operator shall not burn in the flares any fuel gas that contains H_2S in excess of 162 ppmv determined on a 3 hour rolling average basis. The combustion in a flare of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions is exempt from this limit. *[Reference: 40 CFR 60.103a(h)]*	Part 2, Condition 3, Table 1	n.1.i.B.
	H. The owner/operator shall develop and implement a written Flare Management Plan in accordance with the provisions found in 40 CFR 60.103a(a) by no later than November 11, 2015. *[Reference: 40 CFR 60.103a(a)-(b)]*	Part 2, Condition 3, Table 1	n.1.i.H.
	I. The owner/operator shall conduct a root cause analysis and corrective action analysis any time SO_2 emissions from the flares exceed 500 lbs in any 24 hour period or when a discharge to the flare in excess of 500,000 scf occurs in any 24 hour period. *[Reference: 40 CFR 60.103a(c)]*	Part 2, Condition 3, Table 1	n.1.i.I.
	J. Each root cause analysis and corrective action analysis required by Operational I above must be completed as soon as possible, but no later than 45 days. Special circumstances affecting the number of root cause analyses and/or corrective action analyses are provided in 40 CFR 60.103a(d)(1) through (5) *[Reference: 40 CFR 60.103(d)]*	Part 2, Condition 3, Table 1	n.1.i.J.
	K. The owner/operator shall implement corrective action(s) identified in the corrective action analysis conducted pursuant to Operational Limitation I in accordance with the applicable requirements found in 40 CFR 60.103a(e)(1) through (3). *[Reference: 40 CFR 60.103a(e)]*	Part 2, Condition 3, Table 1	n.1.i.K.
	L. The owner/operator shall comply with the requirements of Operational Limitations (I) through (L) by November 11, 2015.	Part 2, Condition 3, Table 1	n.1.i.L.
	Compliance with Emissions Limitation B shall be demonstrated in accordance with the monitoring/testing and recordkeeping requirements of	Part 2, Condition 3, Table 1	n.iii.D.

	this condition.		
	Monitoring/Testing: *[Reference: 7 **DE Admin. Code** 1130 Section 6.1.3.1.2 dated 12/11/00]* The Owner/Operator shall continuously monitor the gas flow to the flares (i.e., the gas not recovered by the recovery compressors). After November 11, 2015, the owner/operator shall install, operate, calibrate and maintain the monitoring device in accordance with 40 CFR 60.107a(f). *[Reference: 40 CFR 60.107a(f)]*	Part 2, Condition 3, Table 1	n.iv.A
	Sulfur Dioxide emissions from the flare shall be monitored as follows: 1. Until Nov. 11, 2015, a gas sample shall be collected from the flare header weekly and analyzed by a gas chromatograph. 2. After November 11, 2015, the owner/operator shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration by volume of H_2S or TRS in the process gases before being burned in any flare in accordance with the requirements of 40 CFR 60.107a. *[Reference: 40 CFR 60.107a(a)(2), (b) and (e)]*	Part 2, Condition 3, Table 1	n.iv.B.1. and n.iv.B.2.
	Pollutants in the flare emissions shall be calculated based on the methods specified in Monitoring/Testing condition B above unless more representative process operating data can be used to provide concentrations that are different from those obtained from the daily analyses.	Part 2, Condition 3, Table 1	n.iv.C.
	As an alternative to Monitoring/Testing Conditions A and B, the owner/operator may comply with the monitoring requirements of 40 CFR 60.107a(g).	Part 2, Condition 3, Table 1	n.iv.F.
	A copy of the flare management plan.*[Reference: 40 CFR 60.108a(c)(1)]*	Part 2, Condition 3, Table 1	n.v.J.
	Records of discharges of sulfur dioxide from the flares in accordance with 40 CFR 60.108a(c)(6)(i)-(iv) and (vii)-(xi).	Part 2, Condition 3, Table 1	n.v.K.
	If the owner or operator elects to comply with 60.107a(e)(2), records of the H2S and total sulfur analyses of each grab or integrated sample, the calculated daily total sulfur-to-H2S ratios, the calculated 10-day average total sulfur-to-H2S ratios and the 95-percent confidence intervals for each 10-day average total sulfur-to-H2S ratio. *[Reference: 40 CFR 60.108a(c)(7)]*	Part 2, Condition 3, Table 1	n.v.L.
	Reporting: That required by Conditions 2(a), 2(b)(9), 2(f)(3), 3(b)(1)(ii), and 3(c)(2) of this permit. *[Reference: 7 **DE Admin. Code** 1130 Sections 6.1.3.2.3 and 6.2.1*	Part 2, Condition 3, Table 1	n.vi.A. and n.vi.B.

	dated 12/11/00] A. After November, 11, 2015, the Owner/Operator shall submit semi-annual excess emissions reports for all periods of excess emissions according to the requirements of 40 CFR 60.7(c) except that the report shall contain the information specified in 40 CFR 60.108a(d)(1) through (7). All reports shall be postmarked by the 30th day following the end of each six month period. *[Reference: 40 CFR 60.7(c) and 60.108a(d)]* B. Within 45 days following any flaring event which triggers the Root Cause and Corrective Action Analyses specified in Operational Limitation I, the owner/operator shall submit to the Department a report containing the information in 40 CFR 60.108a(c)(6)(i)-(iv) and (vii)-(xi) and containing the information required by Section 2.5 of DNREC Regulation 1203 (Reporting of a Discharge of a Pollutant or Air Contaminant). Timely reporting pursuant to this condition shall satisfy all requirements for reporting pursuant to DNREC Regulation 1203.		

FACILITY WIDE REQUIREMENTS

There are no changes to the applicable facility wide requirements in this permitting action.

1990 CAAA, Section 112(r)
The facility is subject to and has registered in compliance with the State of Delaware.

1990 CAAA, Title VI
The facility has air conditioners and refrigeration equipment that use CFCs, HCFCs, or other ozone depleting substances. The equipment contains a refrigerant charge greater than 50 pounds. Facility personnel do maintain, service, repair or dispose of any motor vehicle air conditioners or appliances, as defined in 40 CFR Part 82.152. The refinery's application states 40 CFR Part 82 subparts B and F are applicable to the facility but not applicable to any unit covered by the Title V part 1 permit.

Compliance Schedule
The facility is not under a compliance schedule.

Permit Shield
The facility has not requested a Permit Shield.

Compliance Assurance Monitoring (CAM) Rule

DCRC's application included an updated CAM plan submitted on Form AQM-1001EE for the Marine Vapor Recover (MVR) System to include the new applicable requirements as a result of the amendment to the MVR permitting action that authorized exporting crude oil from the DCR[8]. The MVR's CAM applicability determinations show it meets the following criteria: (1) it is located at a major source that requires a Title V permit (2) its subject to an emission limitation for a regulated air pollutant that is not exempt (3) it uses an add on control to achieve compliance with the emission limitation (4) it has pre-control device emissions that are greater than the major source threshold and (5) it is not an exempt backup utility power emissions unit.

Barge loading operations at the loading piers have a potential to emit VOC emissions greater than the major source threshold of 25 TPY. The MVR System uses an induced flow vapor recovery system routed to enclosed flares to reduce emissions by 98% by weight or to 1,000 ppmv.

The refinery's CAM plan states it will use the loading rate and the flame presence as indicators of its monitoring approach.

Table 12

	Indicator No. 1	Indicator No. 2
Monitoring Approach and Permit Citation	DCRC shall continuously monitor the hourly loading rate of all gasoline products and crude oil at each pier during loading operations	A sensing device shall be calibrated, maintained and operated to indicate the continuous presence of a flame at the pilot light during

[8] **Permit: APC-95/0471-C/O (A-3)(LAER)(MACT)(NSPS)** dated 05.31.2013

		the entire loading cycle.
	Part 2, Table 1.b.5.iv.A	Part 2, Table 1.b.5.iv.B
Indicator Range and Permit Citation	Barge loading of gasoline products shall not exceed the following rates: 1. 35,000 barrels hour when loading simultaneously at two piers; and 2. 25,000 barrels per hour at one pier 3. Maximum barge loading of crude oil shall not exceed 7,000 barrels per hour	A flame must be present during the entire loading cycle.
	Part 2, Table 1.b.5.ii.A	Part 2, Table 1.b.5.ii.G
Performance Criteria: Specifications for Obtaining Representative Data	Flow meters are installed on each gasoline and crude oil loading line to each pier.	UV flame detectors are installed on each of the 3 pilots to each MVR unit.
Performance Criteria: Verification Procedures	Stack testing is conducted in accordance with Condition 3, Table 1 – (b)(5)(iv)(C) every 5 years to verify compliance with the VOC emission limitations.	Stack testing is conducted in accordance with Condition 3, Table 1 – (b)(5)(iv)(C) every 5 years to verify compliance with the VOC emission limitations.
Performance Criteria: QA/QC Practices	Stack testing is conducted in accordance with Condition 3, Table 1 – (b)(5)(iv)(C) every 5 years to verify compliance with the VOC emission limitations.	Stack testing is conducted in accordance with Condition 3, Table 1 – (b)(5)(iv)(C) every 5 years to verify compliance with the VOC emission limitations.
Performance Criteria: Monitoring Frequency	Continuous	Continuous
Performance Criteria: Data Collection Procedures	Data will be collected and stored via the Refinery Process Historian	The process control software contains an interlock which automatically shuts down flow to the MVR should a flame not be detected in the mVR
Performance Criteria: Data Averaging Period	Hourly average basis	Not applicable

Stack testing, required every 5 years per Part 2 Condition 3 – Table 1.b.5.iv.C, is performed to ensure compliance. The last stack test was performed in December 2013 and showed the MVR system to be in compliance with applicable requirements.

<u>RECOMMENDATION</u>
It is recommended the attached draft/proposed operating permit be issued to the Company and advertised in the News Journal for the 30-day public review period and the affected states of Maryland, New Jersey and Pennsylvania. This draft/proposed permit will also be made available

concurrently to the US EPA for 45 days for its review.

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pc: Dover Title V File
Paul E. Foster, P.E.